CO_2 Capture From *Existing* Coal-Fired Power Plants

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Overview

<u>Purpose</u>: To perform a thorough engineering and economic analysis helps answer the following questions:

If carbon constraints are mandated in the U.S. then…..

1. Will retrofit of an **existing** pulverized coal plant at some **modest but non-trivial level** of CO_2 removal ever be a worthwhile option to consider?

2. What level of CO_2 recovery is economically optimal?

3. Is there a way to significantly reduce the cost of CO_2 capture for the **existing** fleet?

4. What actions would need to be taken to address **existing** power plants?

Background—Fall 2005 Scoping Study

Question : Is there enough information in the literature to answer these questions?

Scoping Study Objectives:

1. Literature search on large-scale CO_2 capture from existing PC plants
2. Identify barriers to CO_2 capture retrofits
3. Investigate all potential cost saving strategies
4. Define 'optimal' level of CO_2 recovery
5. Is there enough information available to calculate the optimal level of CO_2 recovery? If not, develop a plan for a more detailed study

Background: Study 1

1991: EPRI/IEA/Fluor Daniel[1]

- New 500 MW PC Plant
- Sensitivity Studies: 50% and 20% CO_2 capture on new plant
- Retrofit 500 MW PC plant using MEA with 90% CO_2 capture

	NEW				Retrofit*
CO_2 Capture, %	**0**	**90**	**50**	**20**	**90**
Gross Power, MW	554	447	488	529	447
Auxiliary Power, MW	41	109	79	53	111
Heat Rate, Btu/kWh	9,800	14,900	12,300	10,600	15,000
Efficiency, %	35	23	28	32	23
COE, cents/kWh	4.2	9.3	7.2	5.7	10
Increase in COE, %	-	>100	71	36	>100

Source: *Engineering and Economic Evaluation of CO2 Removal from Fossil-Fuel-Fired Power Plants,* IE-7365, Fluor Daniel, Irvine, CA., IEA, France, EPRI, Palo Alto, CA. (1991)

Background: Source 2

2001: DOE-NETL/Alstom Power

- Retrofit of AEP's Conesville Unit #5 (463 MW) plant via

  1.) MEA scrubbing, 2.) Oxy-fuel combustion, 3.) MEA/MDEA scrubbing

- Minimum 90% flue gas CO_2 captured

Conclusions

- "…oxy-fuel most promising for 90% capture, but MEA and MEA/DEA scrubbing 'appears' to be cheaper at <90% capture levels…"

- "…specific investment costs are high, ranging from about **800 to1800 $/kW**…"

- "…all cases indicate significant increases to the COE as a result of CO_2 capture—about **6.2 cents/kWh** (2001$)"

Source: Engineering Feasibility and Economics of CO_2 Capture on and Existing Coal-Fired Power Plant, DOE/NETL, Pittsburgh, PA., Alstom Power, Windsor, CT. (2000)

Background: Source 3

2004: Canadian Clean Coal Power Coalition/IEA GHG

- Objective: "To demonstrate that coal-fired electricity generation can effectively address all environmental issues projected in the future, including CO_2."
- Evaluated amine scrubbing and oxy-fuel combustion for existing PC power plants and gasification for new power plants

Conclusions

- Identified significant opportunities to optimize amine scrubbing efficiency via heat integration---ONLY with a New Plant!

- "…during the course of Fluor's studies it became apparent that retrofits would be less attractive than expected. Therefore, the later stages of the studies concentrated on greenfield applications for all technologies…"

Source: Canadian Clean Coal Power Coalition Studies on CO2 Capture and Storage
IEA GHG, PH 4/27 (March 2004)

Background: Source 4

2004: Nexant for the CO_2 Capture Project (CCP)

- Cost reduction opportunities for an NGCC post-combustion retrofit system using advanced amines
- Identified 8 significant cost cutting ideas for NGCC retrofits

	1	2	BIT
CO_2 Capture, %	**0**	**90**	**90**
Net Power, MW	392	322	357
Efficiency, %	57.6	47.3	52.5
$/tonne CO_2 Avoided	-	**60** →	**28.2**

- Cost reduction is too impressive to be ignored
- Question is: Could some of Nexant's recommendations be applied to a retrofit PC power plant?

Source: CO2 Capture Project: Post-Combustion "Best Integrated Technology" (BIT) Overview
Chinn, D. (Chevron Texaco), Eimer, D. (Norsk Hydro), Hurst, P. (BP), 2004 Carbon Sequestration Conference

Barriers to CO_2 Retrofits

1. Lower efficiency due to less energy integration—plant operation at non-optimum conditions
2. Limited regeneration steam availability—can steam turbine operate at part load?
3. Major equipment modifications or redundancy
4. May need separate utility systems, such as cooling water supply for the capture unit, less economies of scale
5. Make-up power—satisfy need to maintain baseload output
6. Sulfur—additional deep sulfur removal required for most CO_2 sorbents
7. Space limitations—acres needed for current scrubbing

Potential Cost Saving Strategies

Technology improvements in past 5-10 years

Potential Retrofit Options	Outcome/Notes
1. Heat Integration	↓ Steam Consumption
2. Minimize equipment needed	↓ Capital cost (ex. No flue gas cooler)
3. Lower cost of materials	↓ Capital cost (stainless vs. carbon steel)
4. Structured column packing	↓ Capital cost, ↓ Sorbent rate (ex. KS1)
5. Plate-and-frame HX	↓ Capital cost
6. ANSI Pumps vs. API Pumps	↓ Capital cost
7. Vapor-recovery system	↓ Steam Consumption
8. Large diameter absorbers	↓ # of Absorbers, ↓ Capital cost
9. Advanced solvents*	↓ Capital cost, ↓ Sorbent circ. rate (ex. KS1)
10. Lower re-boiler duty	↓ Steam Consumption

***Example:**

Current amines (MEA) require at least 1,600 Btu/lb CO_2 captured
Fluor Econamine FG+ requires 1,300-1,400 Btu/lb CO_2 captured
Mitsubishi's KS-1 solvent requires 1,200 Btu/lb CO_2 captured

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Optimal versus Required CO_2 Removal

1. **The capture rate that results in minimum \$/tonne CO_2 avoided or \$/ton CO_2 captured**

2. **Fraction CO_2 removed at specified COE or \$/tonne avoided**

3. **$\Delta COE_{retrofit}$ (x% capture) = $\Delta COE_{greenfield}$ (90% capture)**

4. **Carbon tax—sufficient removal rate such that incremental COE equals the carbon tax**

Scoping Study Conclusions

1. Minimal economic and performance data exists for CO_2 capture from *existing* pulverized coal power plants
2. Majority analyses focused on 90% CO_2 capture from **new** plants
3. Significant improvements in CO_2 scrubbing technologies in past 5-10 years
4. *Detailed Systems Analysis Recommended*

Carbon Sequestration From Existing Power Plants Feasibility Study

December 2005—December 2006

Randall Gas Technologies

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Study Scope

1. 30%, 50%, 70%, 90% and CO_2 capture levels
2. Employ scrubbing technology advances
3. Detailed steam turbine analysis by ALSTOM's steam turbine retrofit group
4. Employ CO_2 capture and compression heat integration
5. Site visits to specify exact equipment location
6. Make-up power via new PC and NGCC (with 90% CO_2 capture)

Design Basis: Assumptions

Economic

Dollars (Constant)	2006
Depreciation (Years)	15
Equity (%)	44
Debt (%)	56
Corporate Tax (%)	20
Discount Rate (%)	7.5
Capital Charge Factor (%)	13.5
Coal ($/MM Btu)	2.11
Capacity Factor (6,307 hr/yr)	72

CO_2 transport and Storage Costs not included

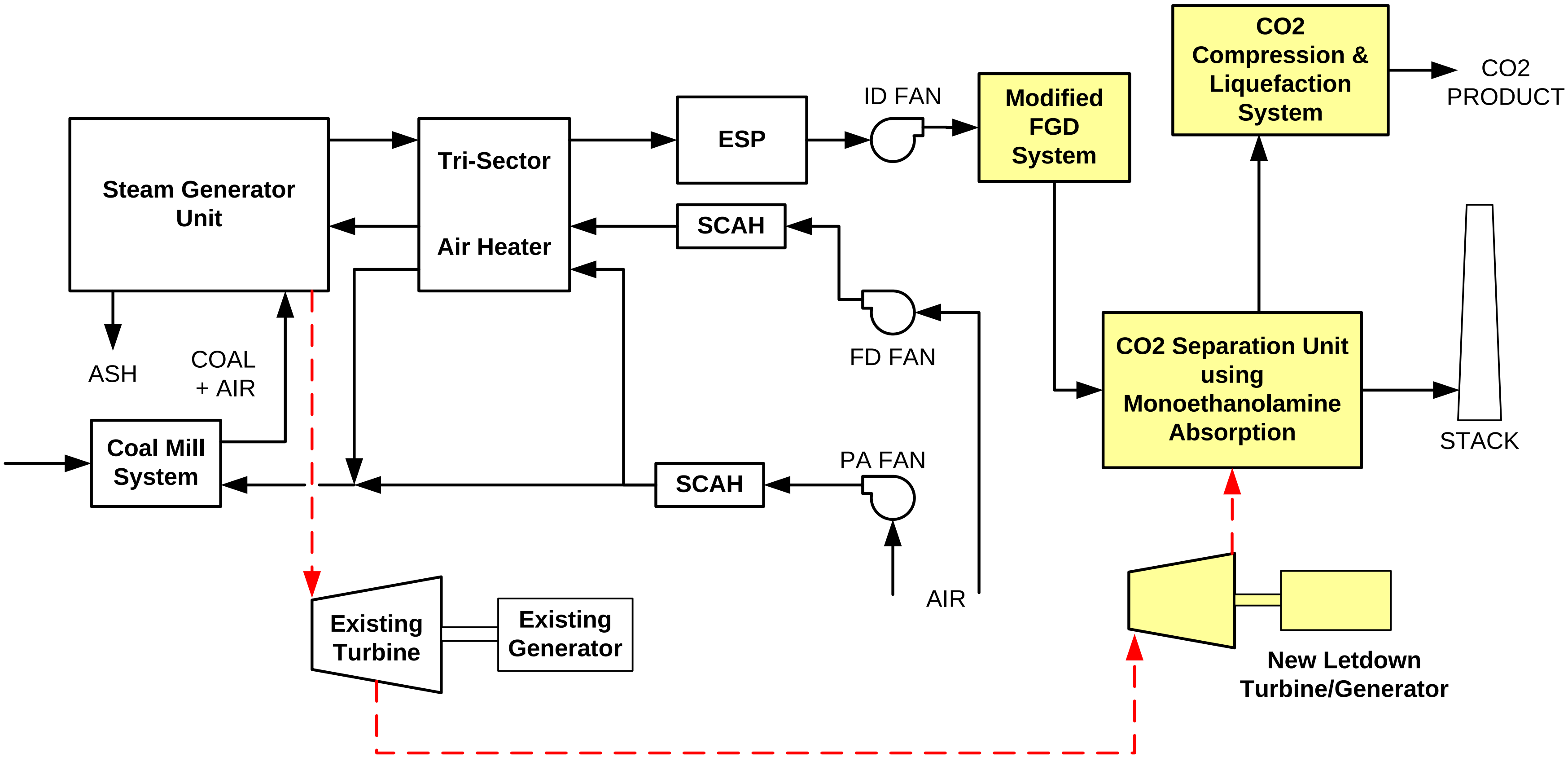
Location: AEP Conesville Unit #5

- **Total 6 units = 2,080 MWe**
- **Unit #5:**
  - Subcritical steam cycle (2400psia/1005°F/1005°F)*
  - Constructed in 1976
  - 463 MW gross (~430 MW net)
  - ESP and Wet lime FGD (95% removal efficiency, 104 ppmv)

Mid-western bituminous coal

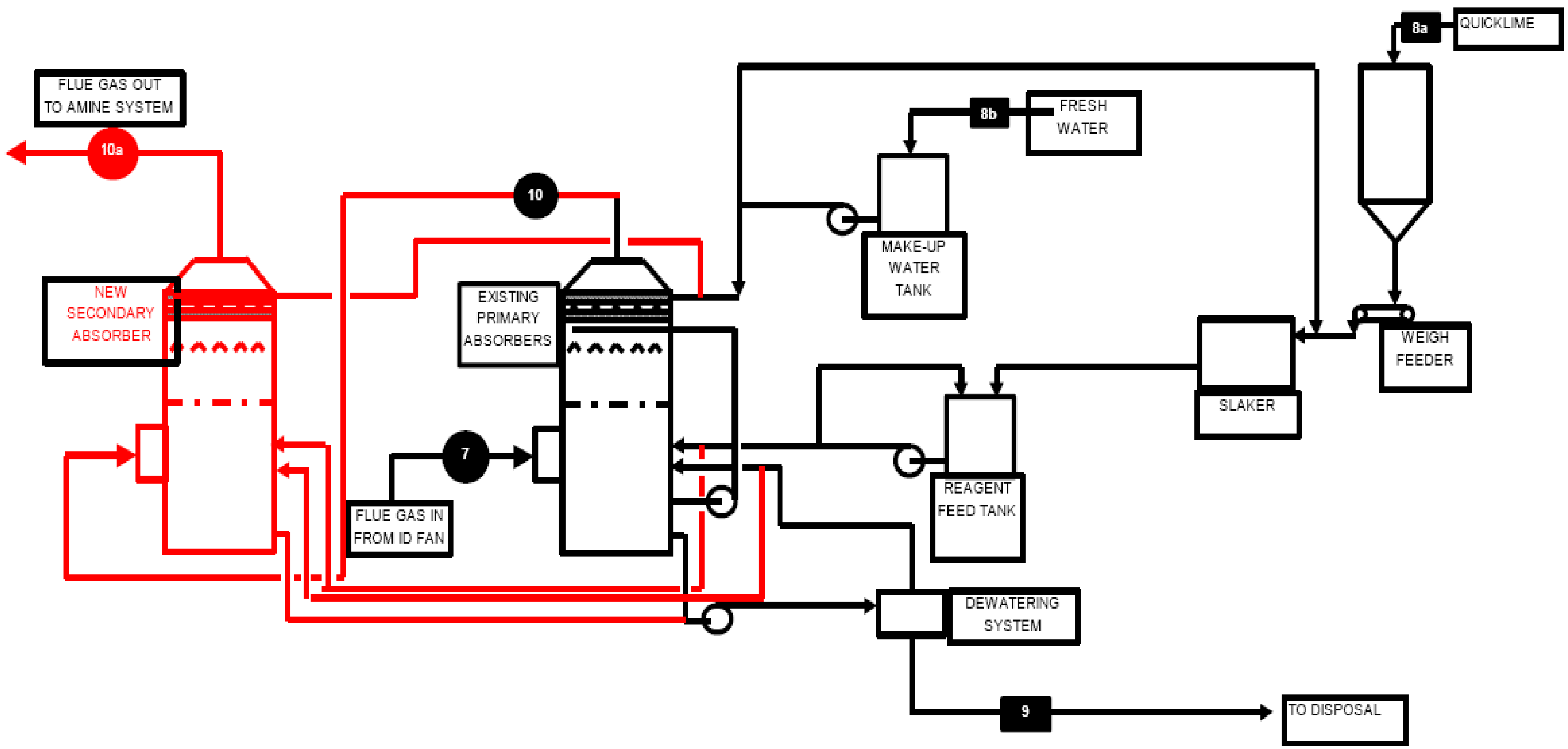
Ultimate Analysis (wt.%)	As Rec'd
Moisture	10.1
Carbon	63.2
Hydrogen	4.3
Nitrogen	1.3
Sulfur	2.7
Ash	11.3
Oxygen	7.1
HHV (Btu/lb)	11,293

Existing Plant Modifications



Modified FGD Process

1. Second stage absorber added to achieve 99.7% SO_2 removal efficiency (6.5 ppmv)
2. Estimated EPC cost for each case (30-90%) is $20.5MM
3. includes an SO_2 Credit equal to $608/ton in the Variable O&M cost



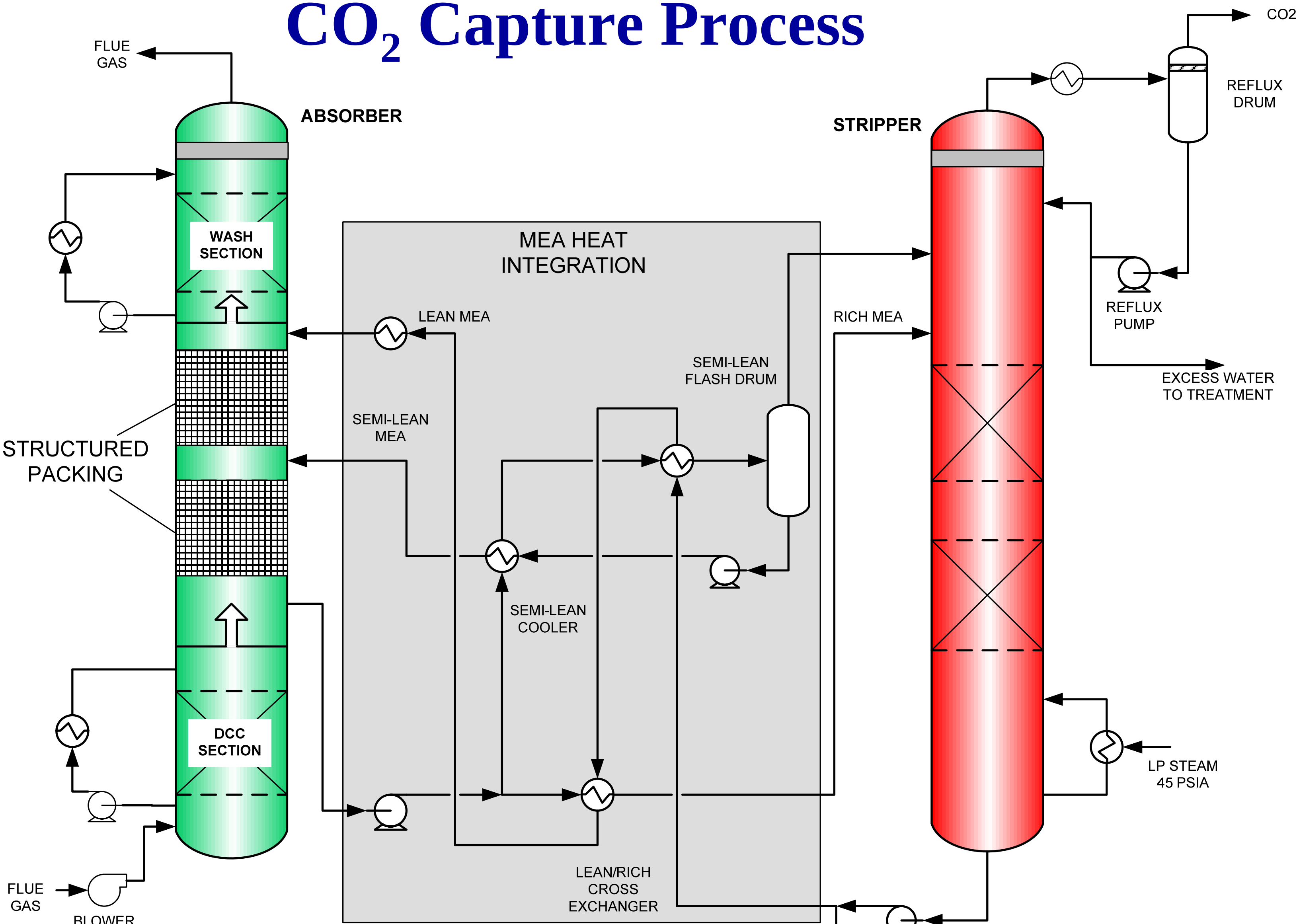
CO_2 Capture Process Key Parameters

Process Paramater	Units	2006	2001	AES Design
Plant Capacity	Ton/Day	9,350-3,120	9,888	200
CO_2 Recovery	%	90-30	90	96
CO_2 in Feed	mol %	12.8	13.9	14.7
SO_2 in Feed	ppmv	10 (Max)	10 (Max)	10 (Max)
Solvent		MEA	MEA	MEA
Solvent Concentration	Wt. %	**30**	**20**	**17-18**
Lean Loading	mol CO_2/mol amine	**0.19**	**0.21**	**0.10**
Rich Loading	mol CO_2/mol amine	**0.49**	**0.44**	**0.41**
Steam Use	lbs Steam/lb CO_2	**1.67**	**2.6**	**3.45**
Stripper Feed Temp	^oF	205	210	194
Stripper Bottom Temp	^oF	247	250	245
Feed Temp to Absorber	^oF	115	105	108

Note: Additional data in “notes pages”

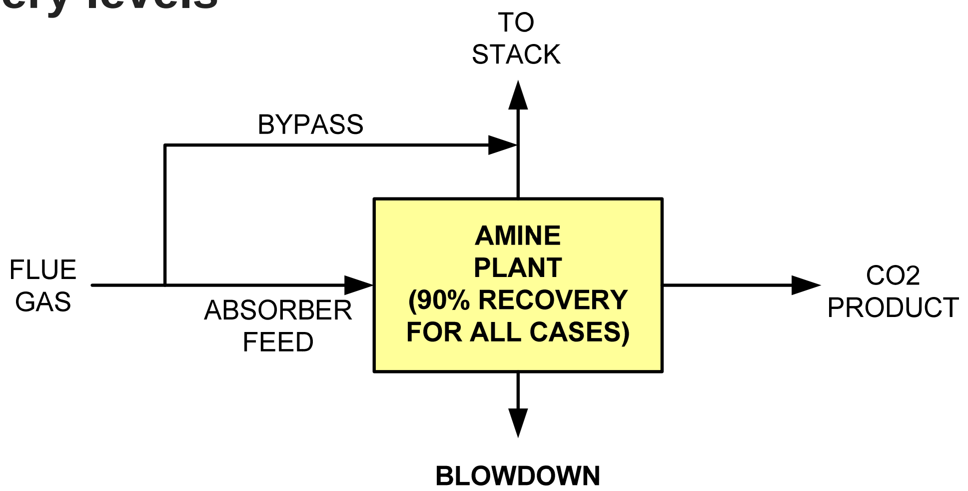
- Reboiler operated at 45 psia—reduced from 65 psia used in 2000 study
- Absorber contains two beds of structured packing

CO_2 Capture Process



Flue Gas Bypass

Bypass method determined to be least costly method to obtain lower CO_2 recovery levels



CO_2 (Moles/hr)	Case 1 (90%)	Case 2 (70%)	Case 3 (50%)	Case 4 (30%)
FLUE GAS	19,680	19,680	19,680	19,680
BYPASS	0	4,374	8,746	13,120
ABSORBER FEED	19,680	15,306	10,934	6,560
STACK	1,962	5,924	9,846	13,770
CO_2 PRODUCT	17,720	13,766	9,822	5,906
# Trains	2	2	2	1

CO_2 Capture Compression, Dehydration and Liquefaction

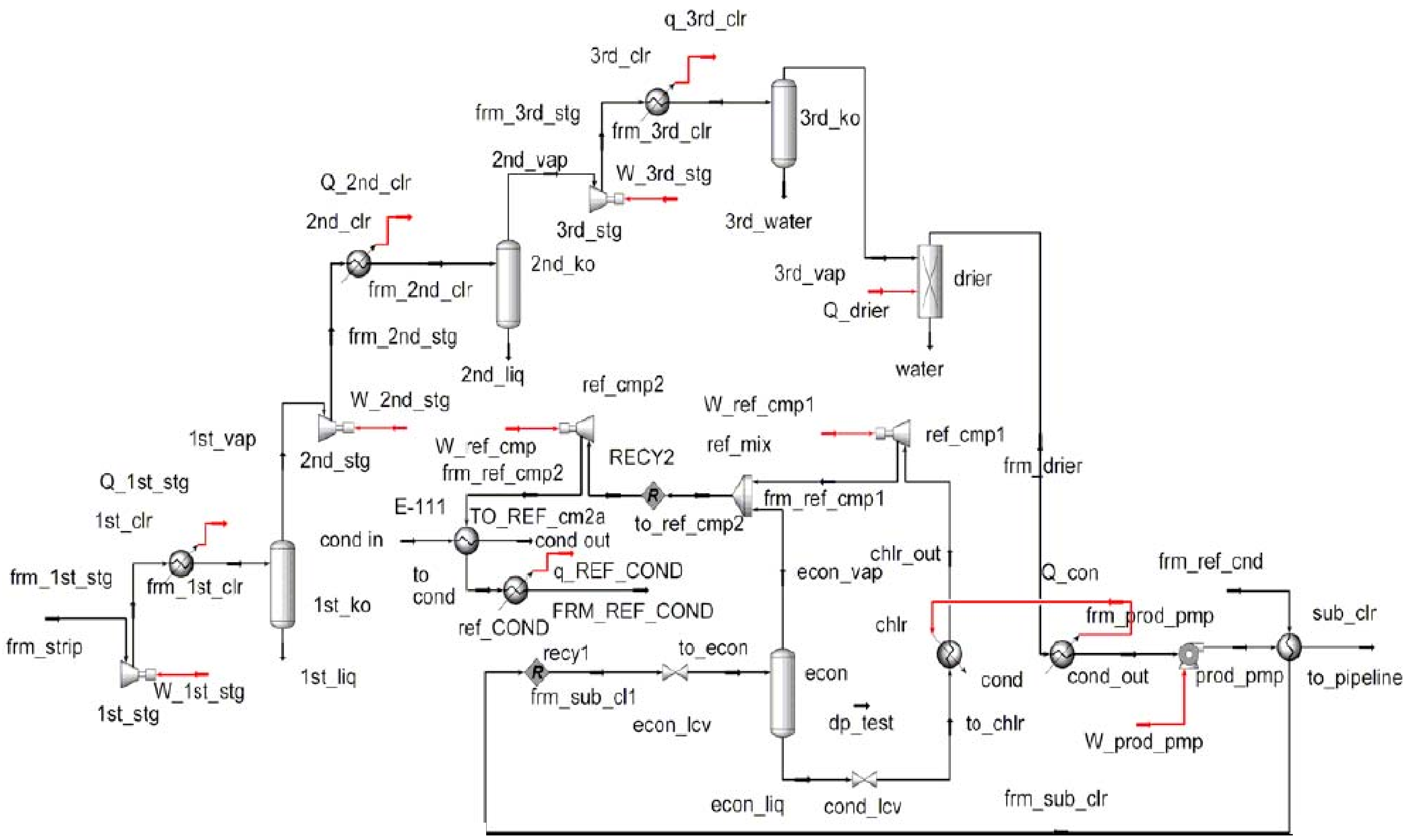
CO_2 compression to 2,015 psia, EOR specifications

Parameter	Wt %	Vol %	ppmv
Carbon Dioxide	96	94.06	940600
C_2+ and Hydrocarbons	2	2.87	28700
Hydrogen Sulfide	1	1.27	12700
Nitrogen	0.6	0.92	9200
Methane	0.3	0.81	8100
Oxygen	0.03	0.04	400
Mercaptans and Other Sulfides	0.03	0.02	200
Moisture	0.006	0.01	100

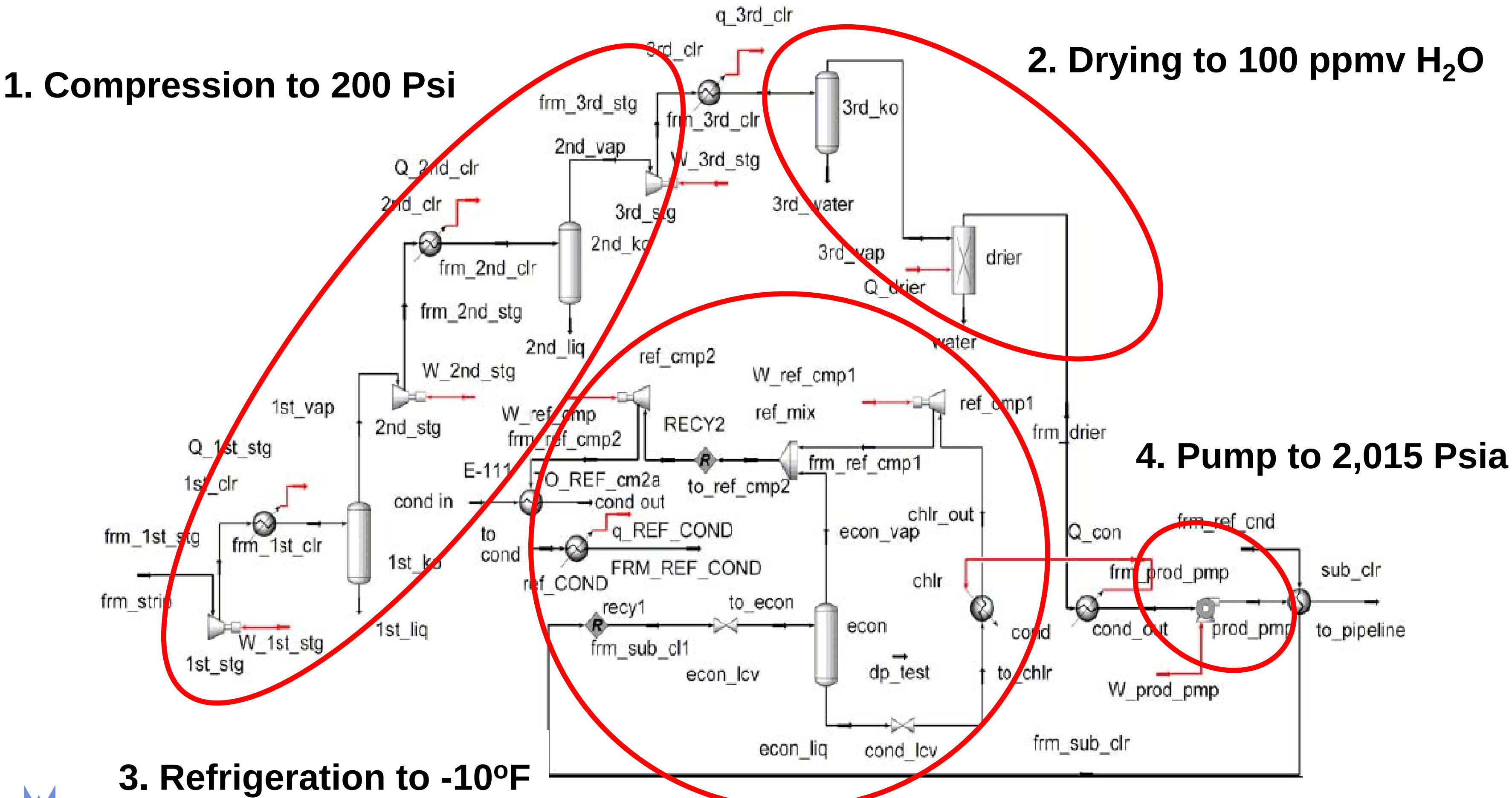
Four Stage Process:

Compression ⇨ Drying ⇨ Refrigeration ⇨ Pumping

CO_2 Capture Compression, Dehydration and Liquefaction



CO_2 Capture Compression, Dehydration and Liquefaction



CO_2 Capture Process Equipment

CO_2 sorbent technology improvements leads to significant decrease in equipment requirements and capital cost!

	2006 Study		2001 Study	
CO_2 Capture Process	No.	ID/Height (ft)	No.	ID/Height (ft)
Absorber	2	34/126	5	27/126
Stripper	2	22/50	9	16/50
Distance from stack	100 ft		1,500 feet	
Heat Exchangers	No.		No.	
Reboilers	10		9	
Stripper CW Cond.	12		9	
Other Heat Exchangers	36		113	
Total Heat Exchangers	**58**		**131**	
CO_2 Compressor	2		7	
Propane Compressor	2		7	
EPC Cost $MM	**276**		**500**	

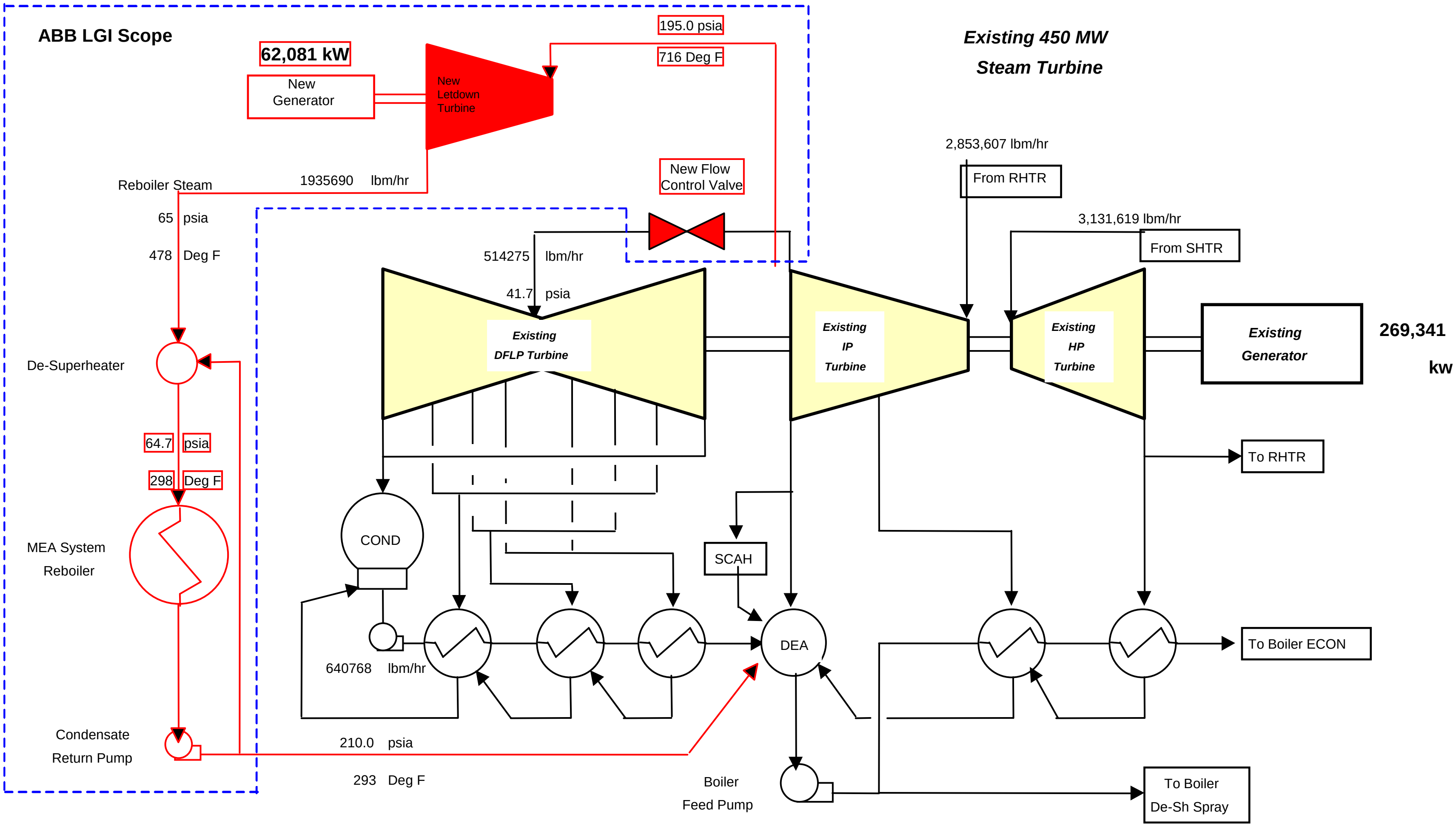
Steam Turbine Modifications

Design Assumptions:

1. **Existing turbine/generator required to operate at maximum load in case of a trip of the MEA plant**
    - All pressures to be within a level that no steam will be blown off
2. **Feedwater system modifications to allow CO_2 capture and compression system heat integration**
    - CO_2 compressor intercoolers, stripper overhead cooler, refrigeration compressor cooler
3. **Well within the LP turbine "lower load limit" after significant steam extraction for the 90% case (Conesville #5 instruction manual)**
4. **New Let Down turbine vs. modifying existing LP turbine**

Steam Turbine Modifications

New Let Down Turbine

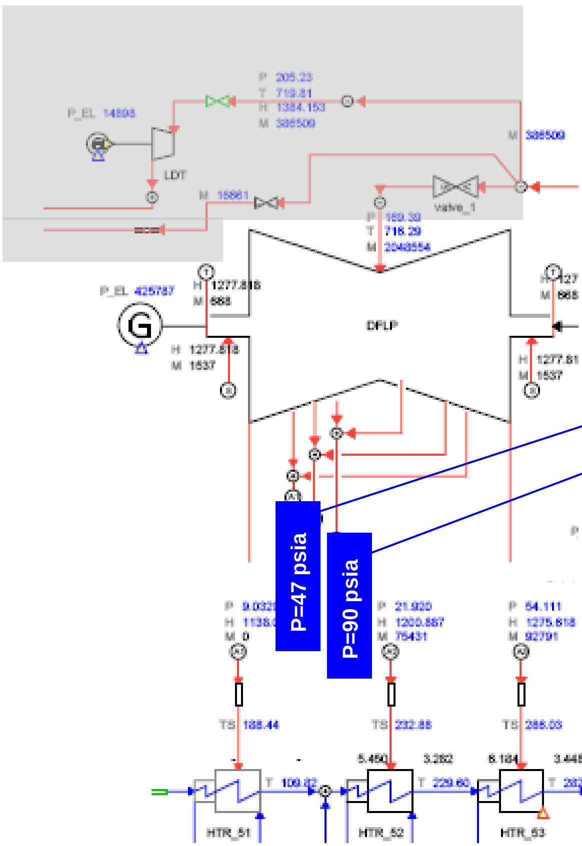


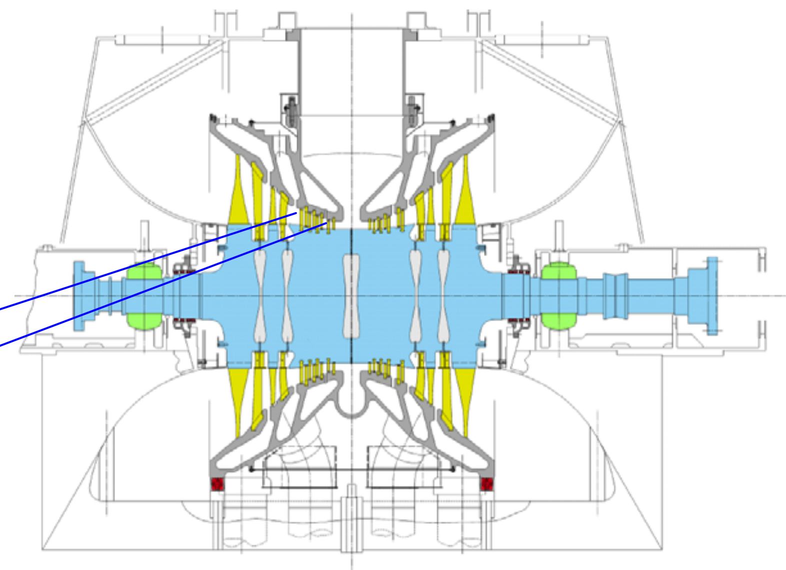
1. New LT output between 15 MW (30%) and 62 MW (90%)
2. EPC Cost ~ $10MM for each case

Steam Turbine Modifications

Alternatives to LDT?

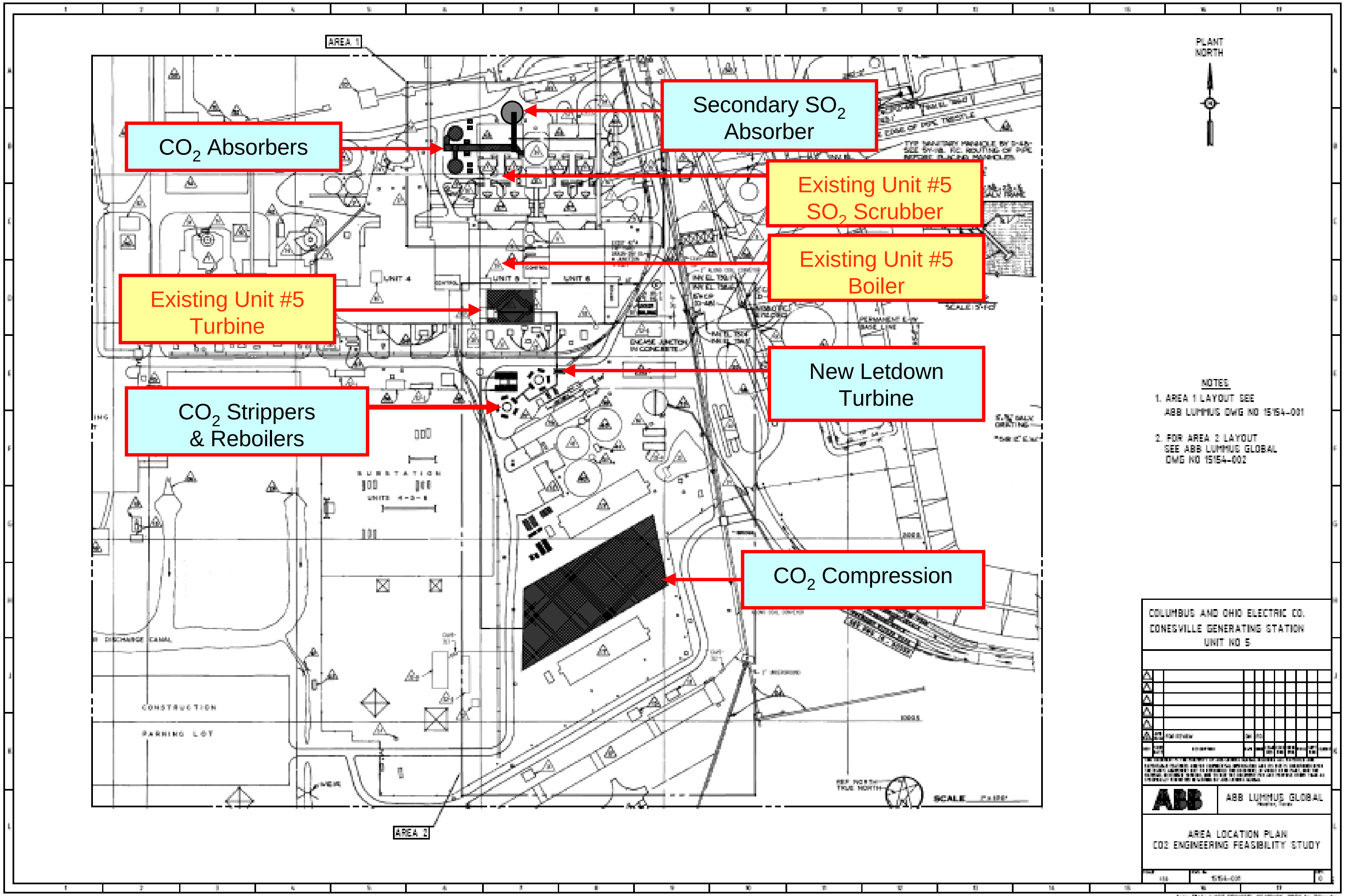
Retrofit solution for 30% Case



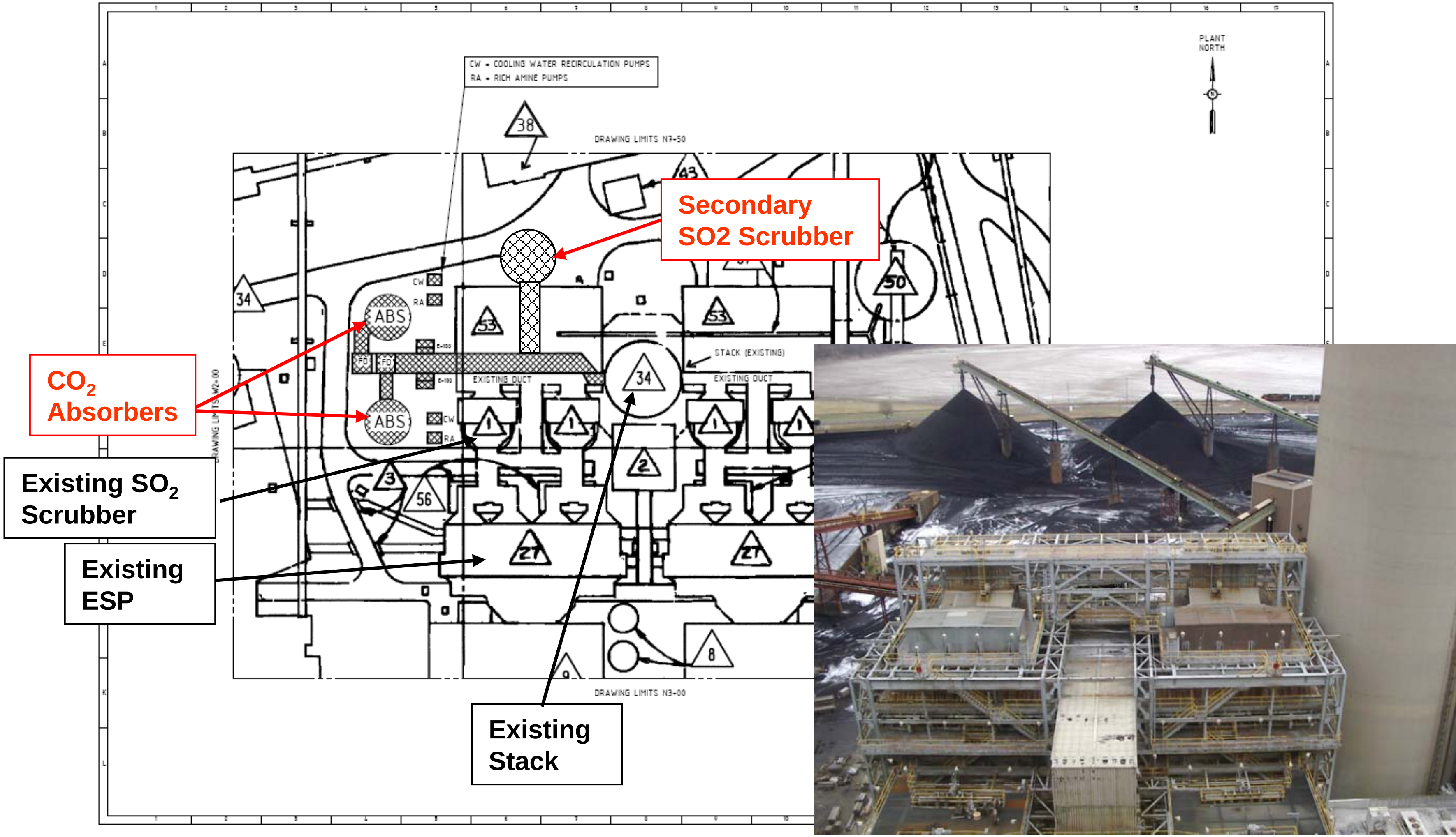


Potential solution by properly matching MEA plant requirements and retrofit design

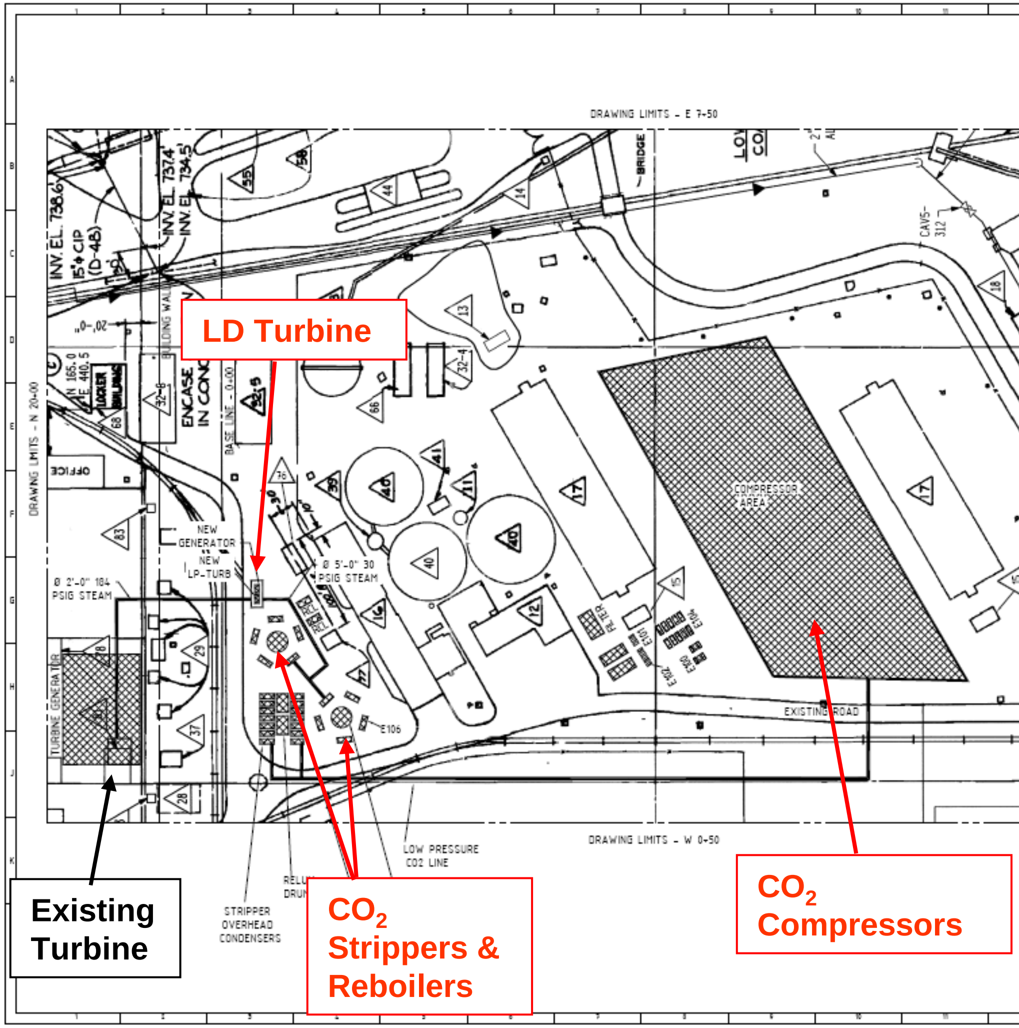
New Equipment Locations Identified



Plot Plan (Absorber location)



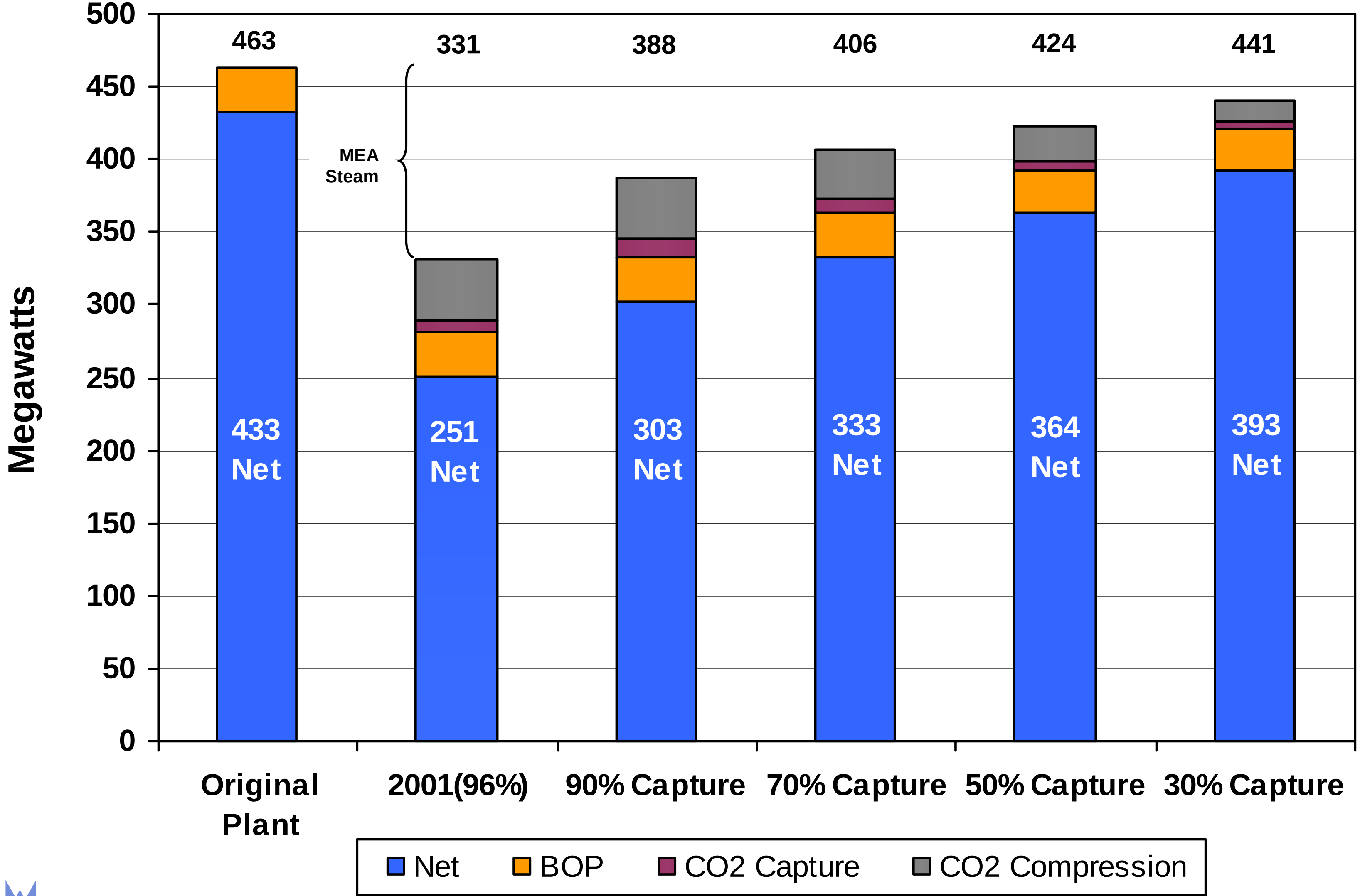
Plot Plan – Let Down Turbine, Strippers, & CO_2 Compressors



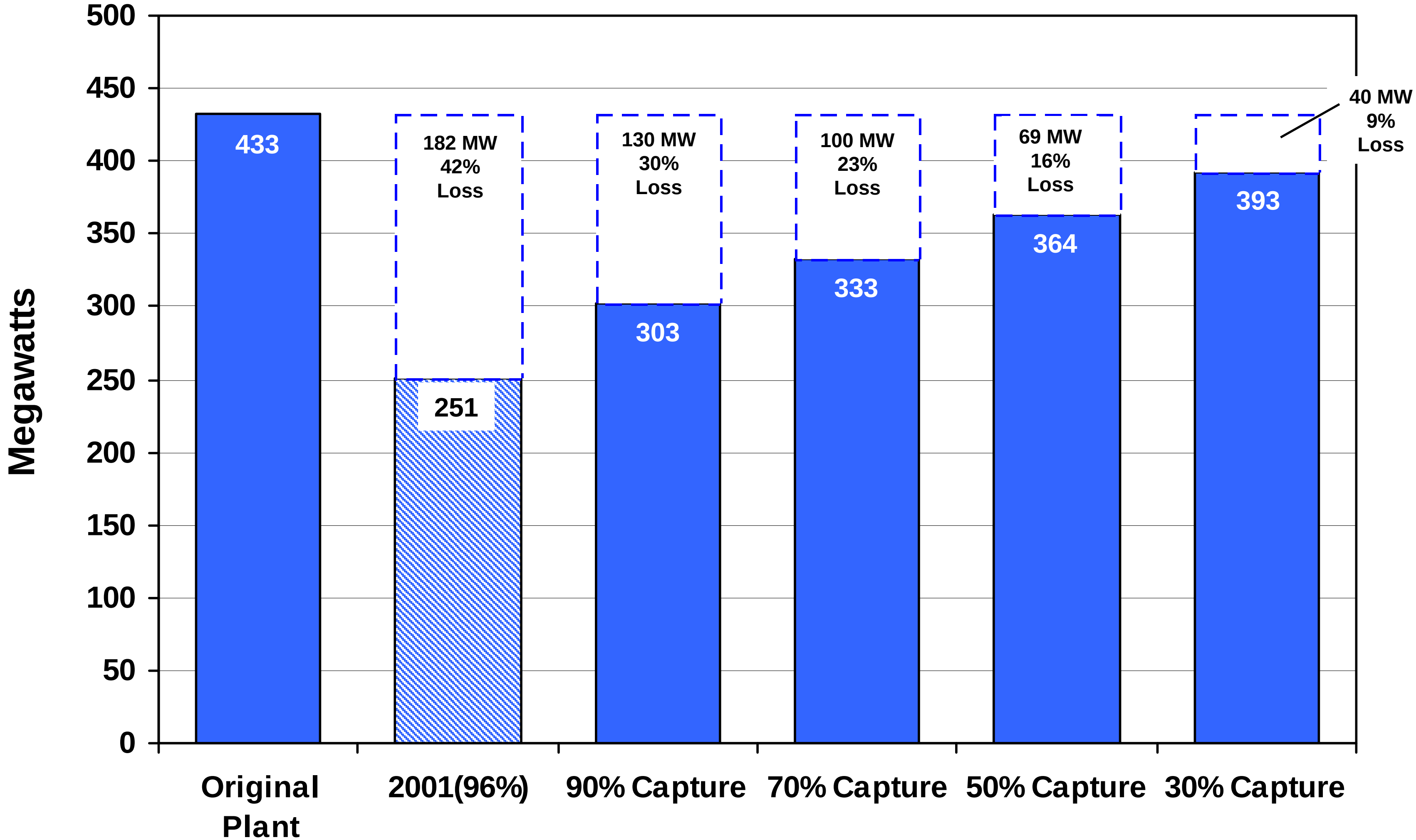
Overall Plant Performance

- Plant Electrical Output
- Plant Auxiliary Power
- Plant Thermal Efficiency
- Plant CO_2 Emissions

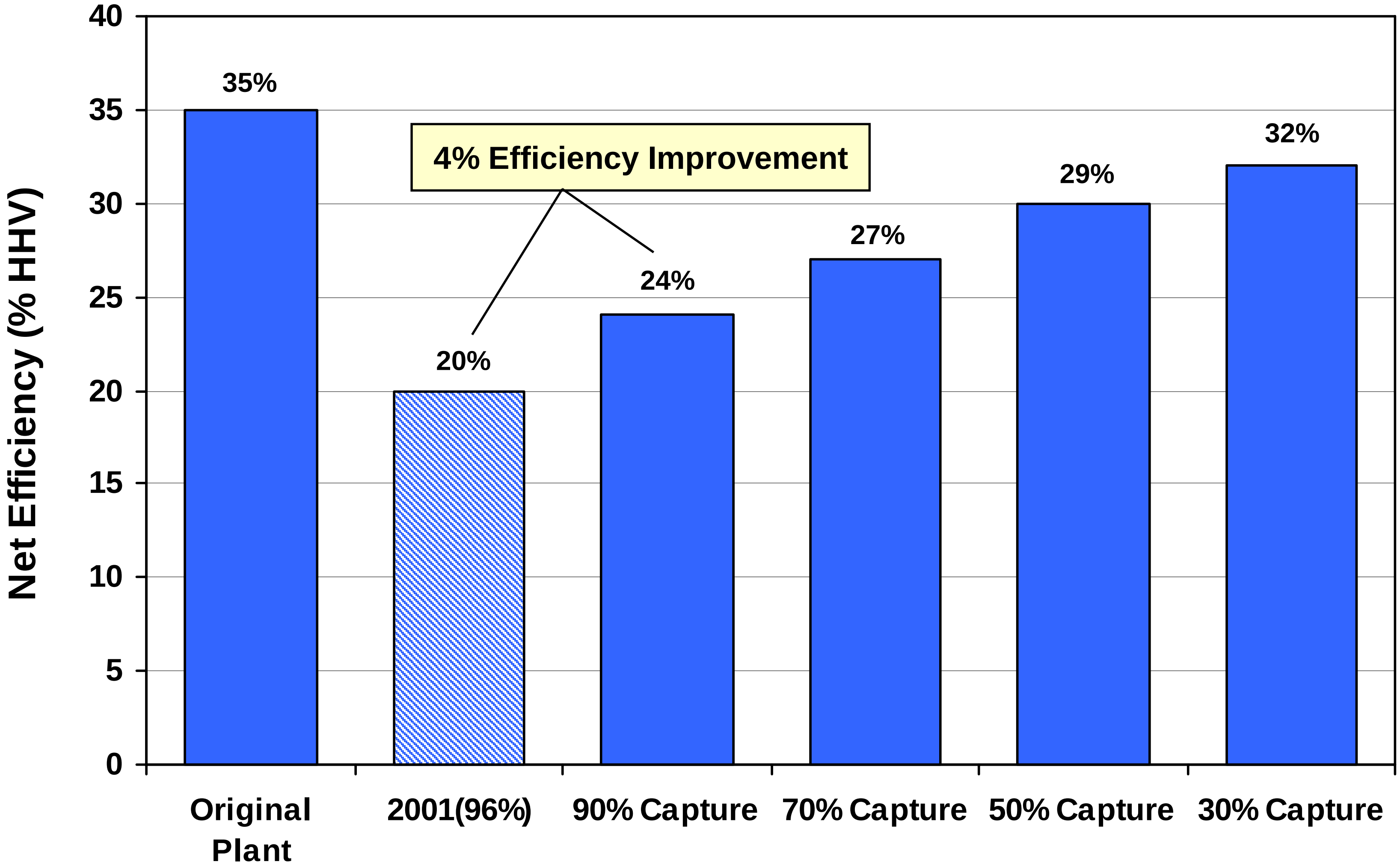
Power Output Distribution



Base load (Net) Output Impact
Losses to Grid



Plant Thermal Efficiency
(HHV Basis)



Note: NEW Sub-critical net efficiency (with 90% CO_2 capture) decreases from 36% to 24%

Summary Performance Results

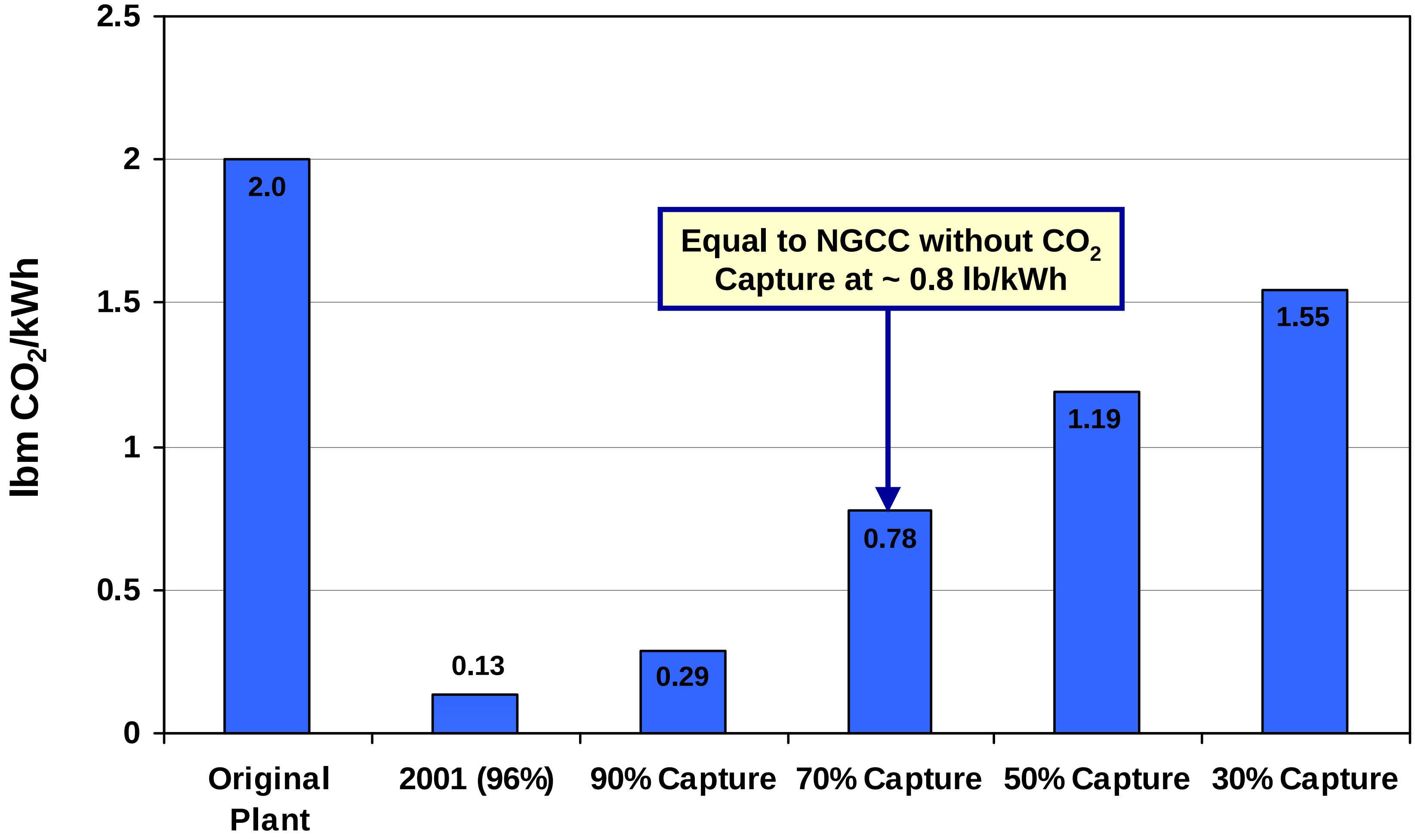
	Base	2001	2006 Study			
% CO_2 Capture	**0**	**96**	**90**	**70**	**50**	**30**
Gross Power (MW)	**463**	**331**	**388**	**406**	**424**	**441**
Base Plant Load	30	30	30	30	30	30
Gas Cleanup/CO_2 Capture	-	8	12	10	6	4
CO_2 Compression	-	42	43	33	24	14
Total Aux. Power (MW)	**30**	**80**	**85**	**73**	**60**	**48**
Net Power (MW)	433	251	303	333	364	393
Heat Rate (Btu/kWh)	9,479	16,875	13,984	12,719	11,670	10,796
Efficiency (HHV)	**35**	**20**	**24**	**27**	**30**	**32**
Energy Penalty[1]	**-**	**15**	**11**	**8**	**5**	**3**

[1] CO_2 Capture Energy Penalty = Percent points decrease in net power plant efficiency due to CO_2 Capture

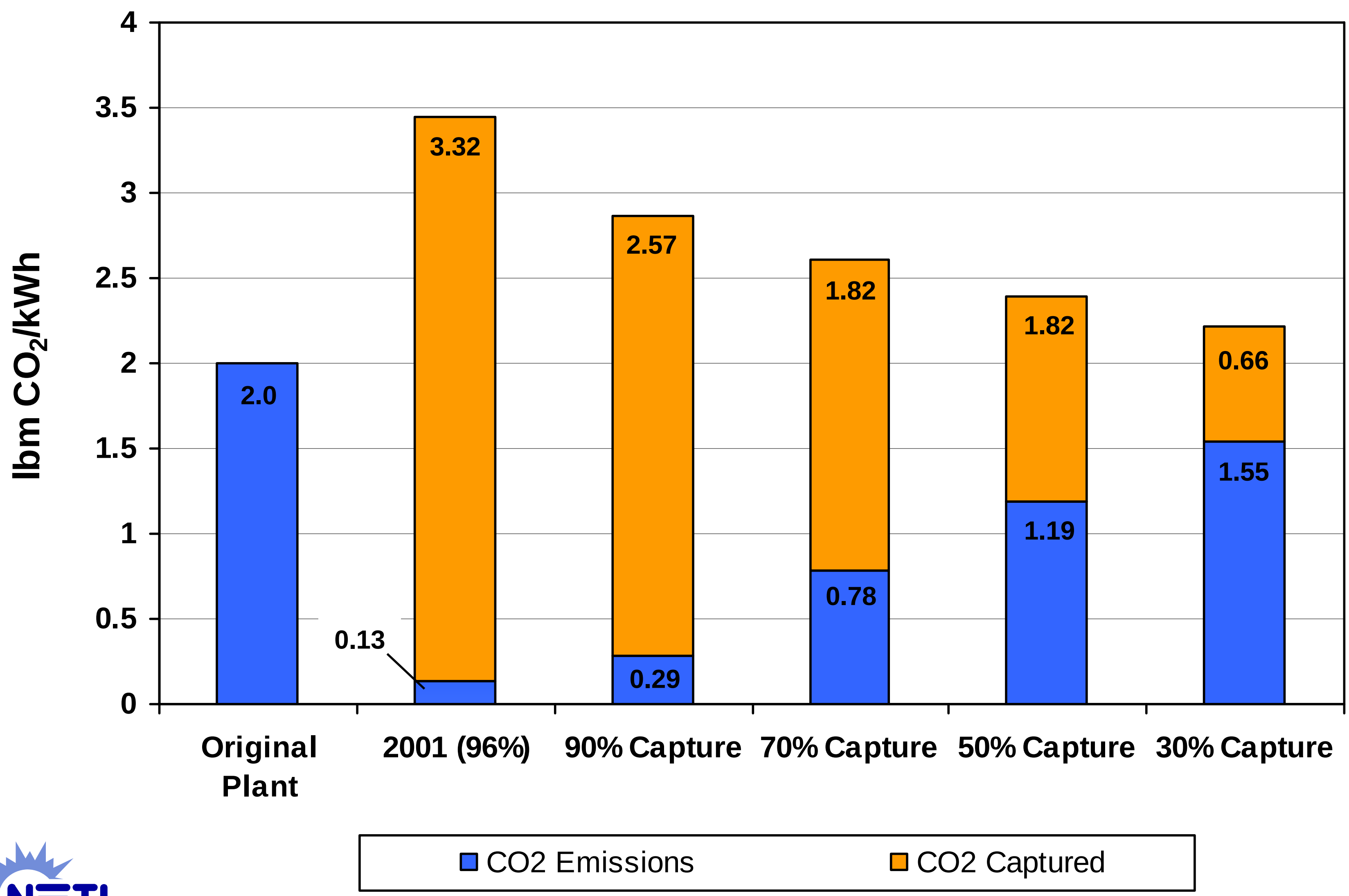
4% Efficiency Improvement

Note: 12% Capture penalty for a new sub-critical plant with MEA Capture
8% Capture penalty for a new super-critical plant with MEA Capture

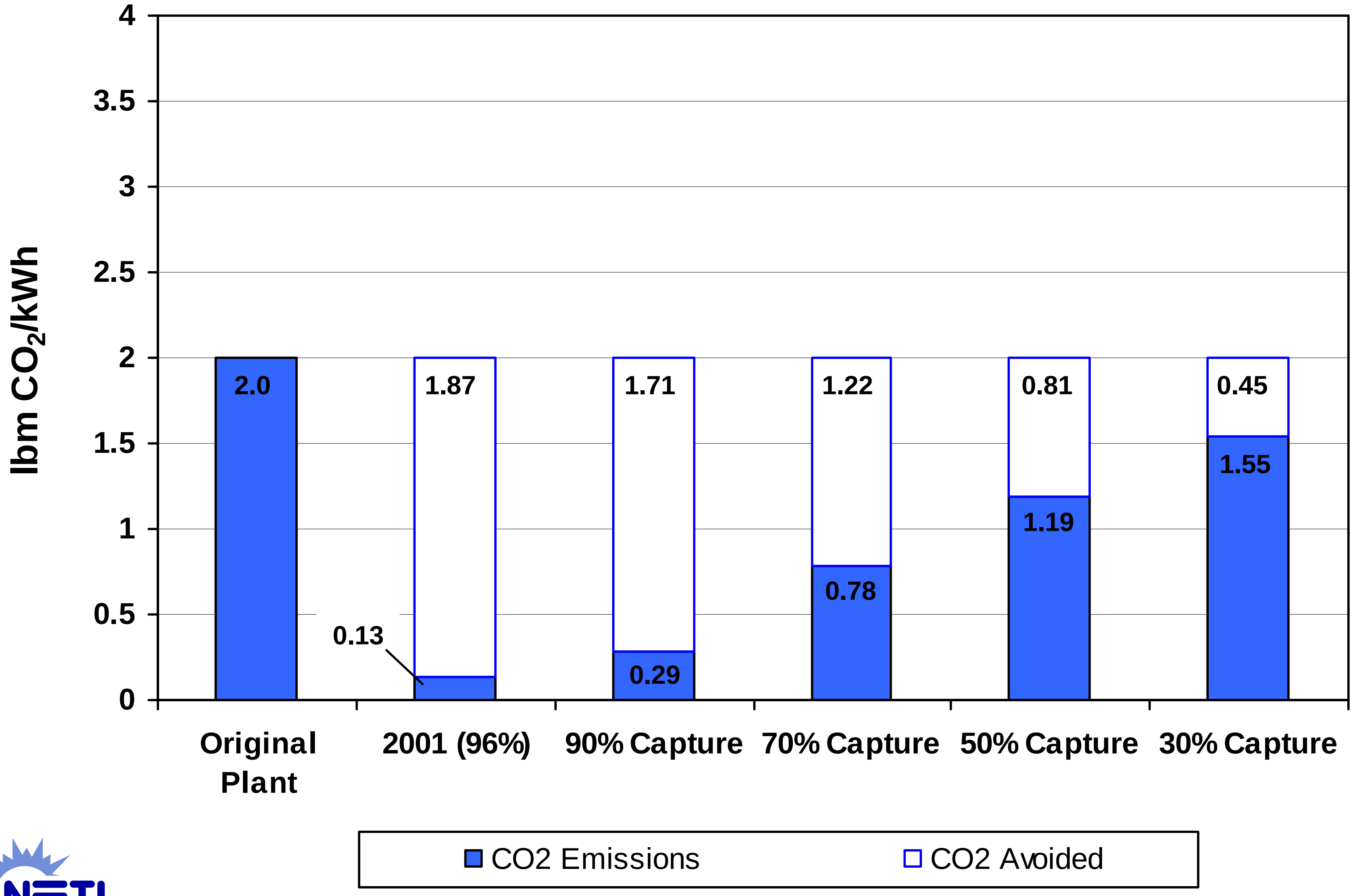
CO_2 Emissions



CO_2 Captured



CO_2 Avoided Emissions



Economics

- Capital Costs
- Incremental COE
- Mitigation Costs
- Sensitivity Analyses

Plant Retrofit Capital Costs

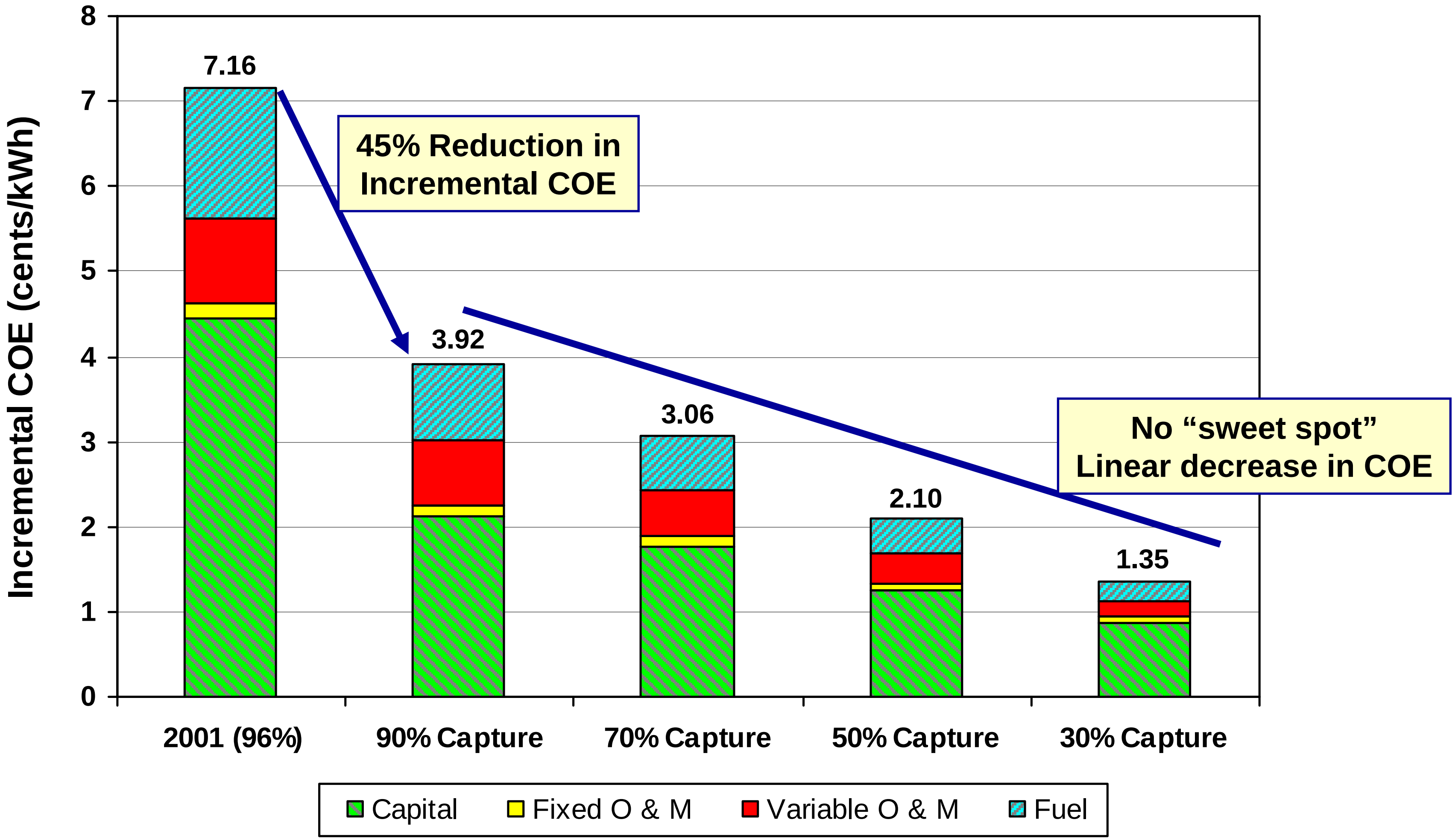
EPC Costs ($1000's)	2001	2006 Study			
% CO_2 Capture	96	90	70	50	30
CO_2 Capture & Compression	500,807	275,938	249,822	186,694	134,509
Flue Gas Desulfurization	20,540	20,540	20,540	20,540	20,540
Letdown Steam Turbine	10,516	9,800	9,400	8,900	8,500
Boiler Modifications	0	0	0	0	0
Total Retrofit Costs	**531,863**	**306,278**	**279,762**	**216,134**	**163,549**
New Net Output (kW)	251,634	303,317	333,245	362,945	392,067
$/kW-New Net Output	**2,114**	**1,010**	**840**	**596**	**417**
$/kW-Original Net Output*	**1,226**	**706**	**645**	**498**	**377**

*Original net output = 433,778 kW

52% Reduction in Incremental Capital Costs

Note: Capital costs from 2001 study were escalated to 2006 dollars

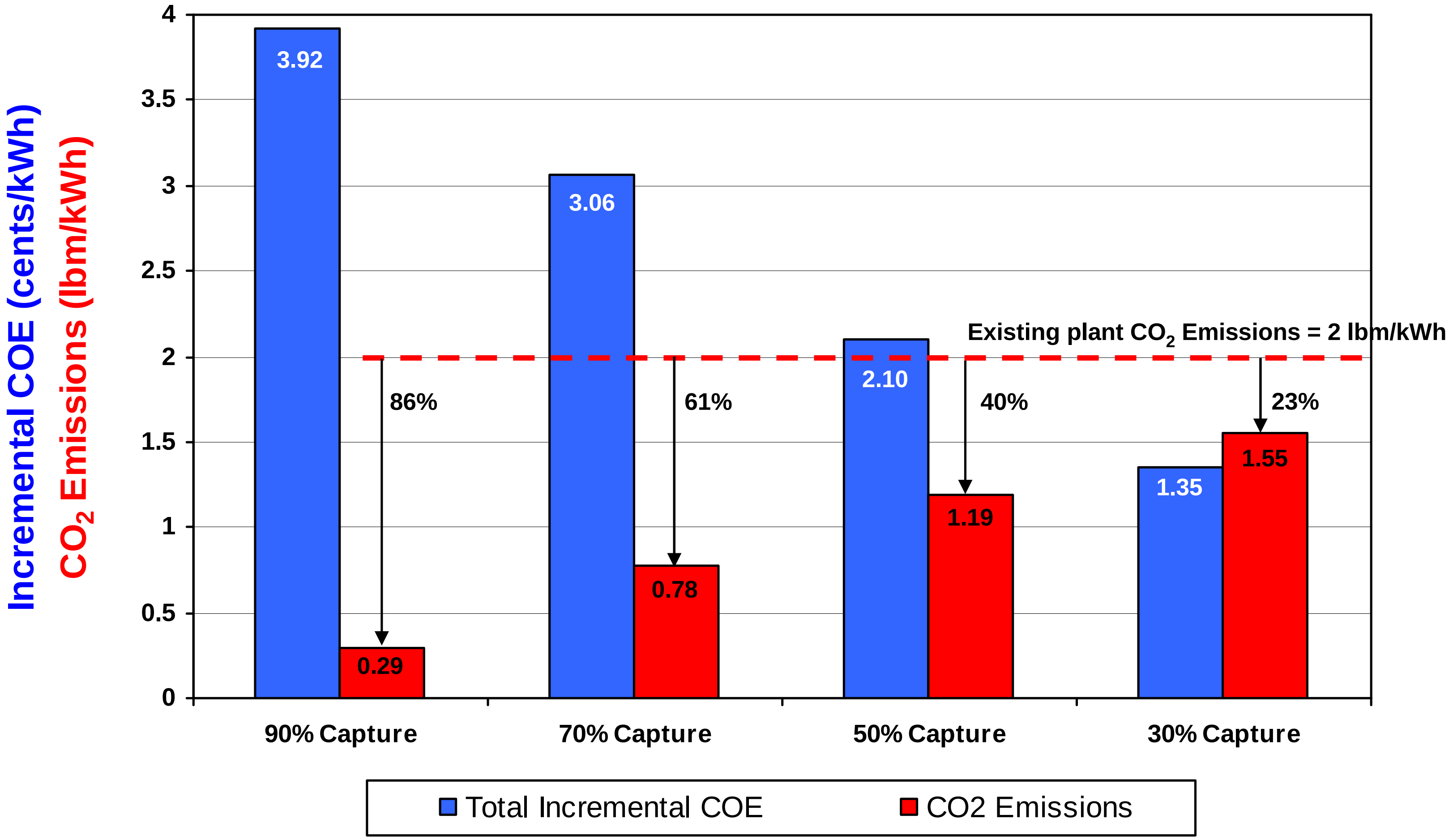
Economic Results



Note:
Economic results from 2001 study were escalated to 2006 dollars
Variable O&M cost includes SO_2 Credit at $608/ton

Economic Results

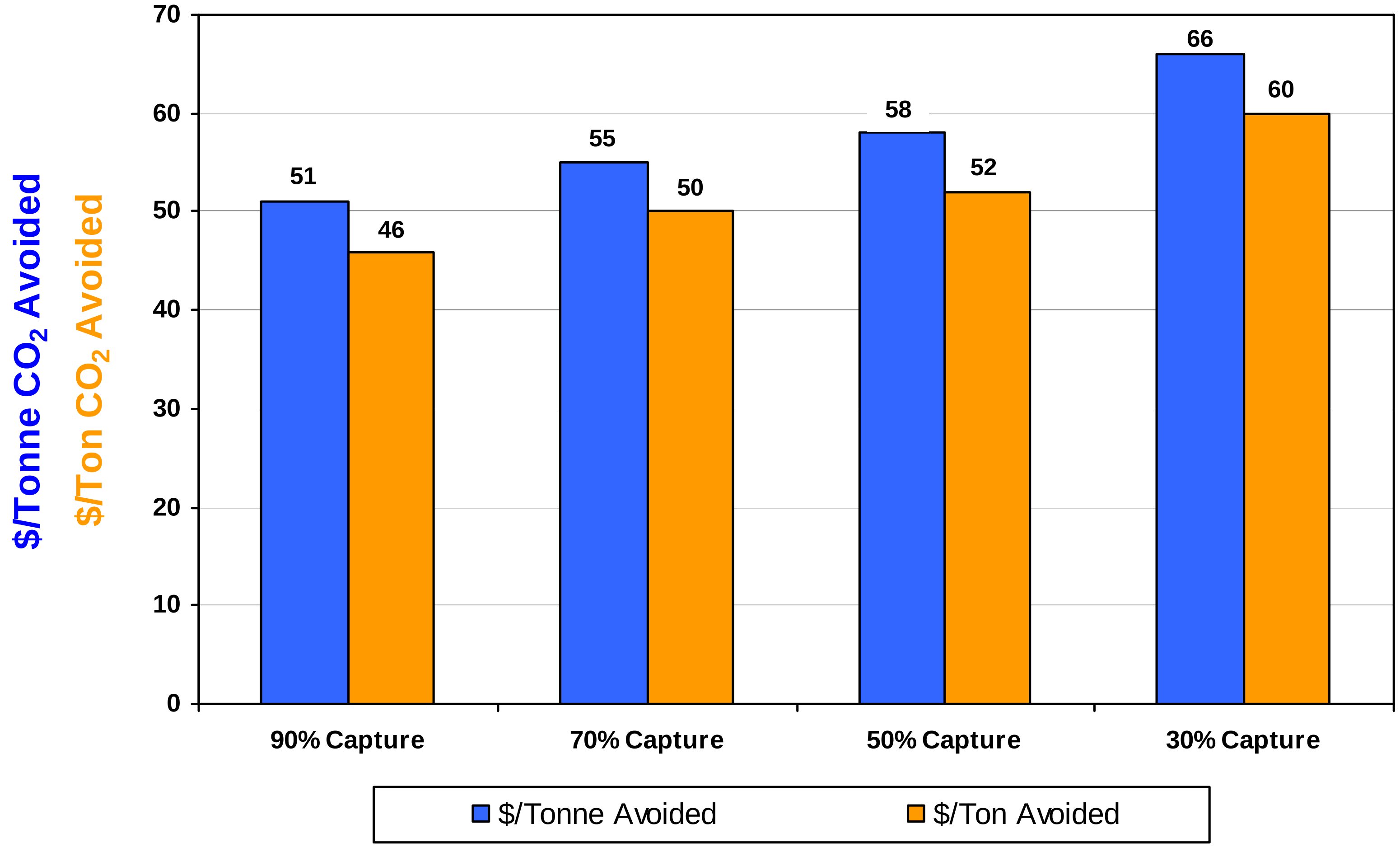
Cost for Reducing Emissions



Note: Economic results from 2001 study were escalated to 2006 dollars

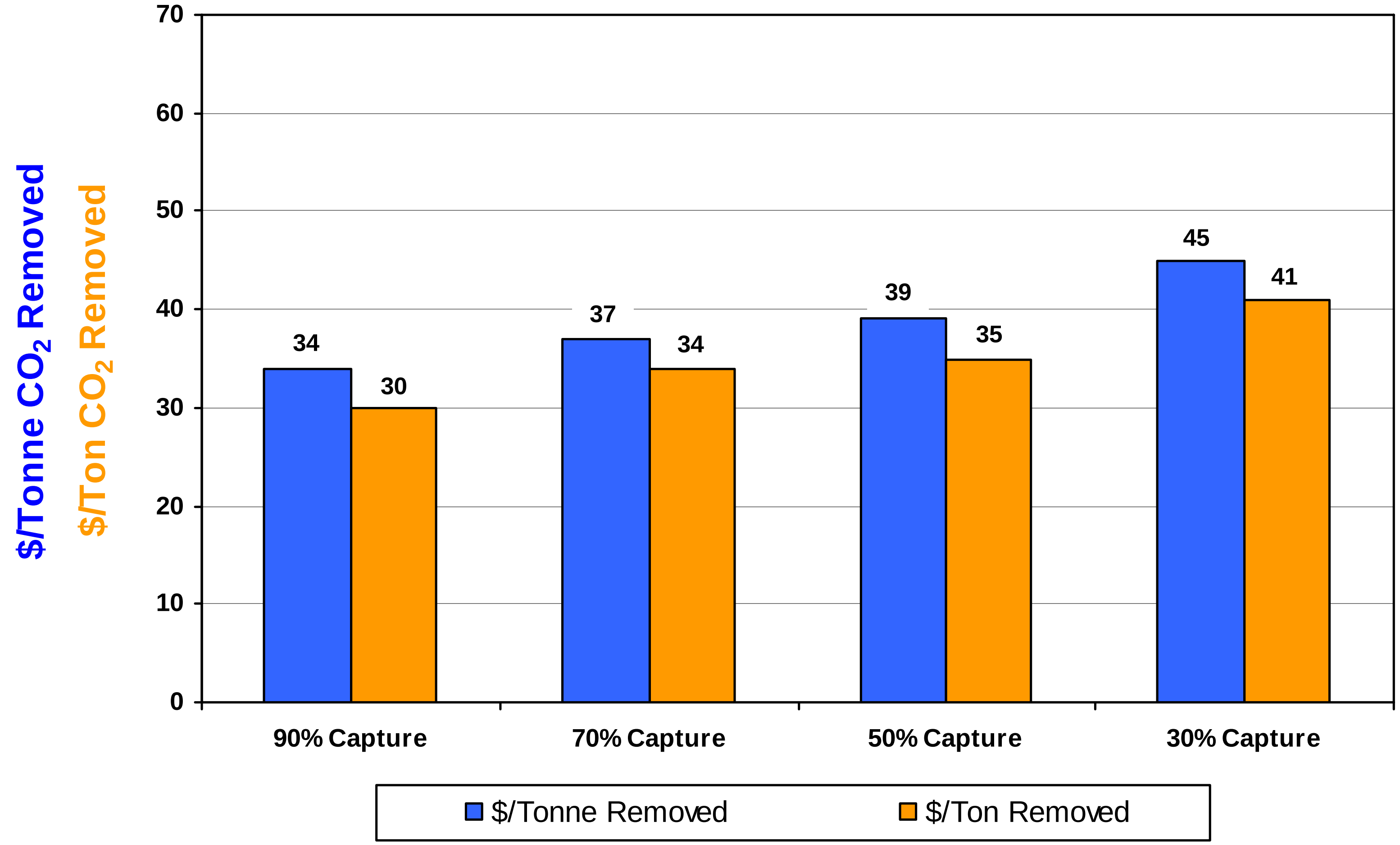
Economic Results

CO_2 Avoided Cost



Economic Results

CO_2 Captured Cost

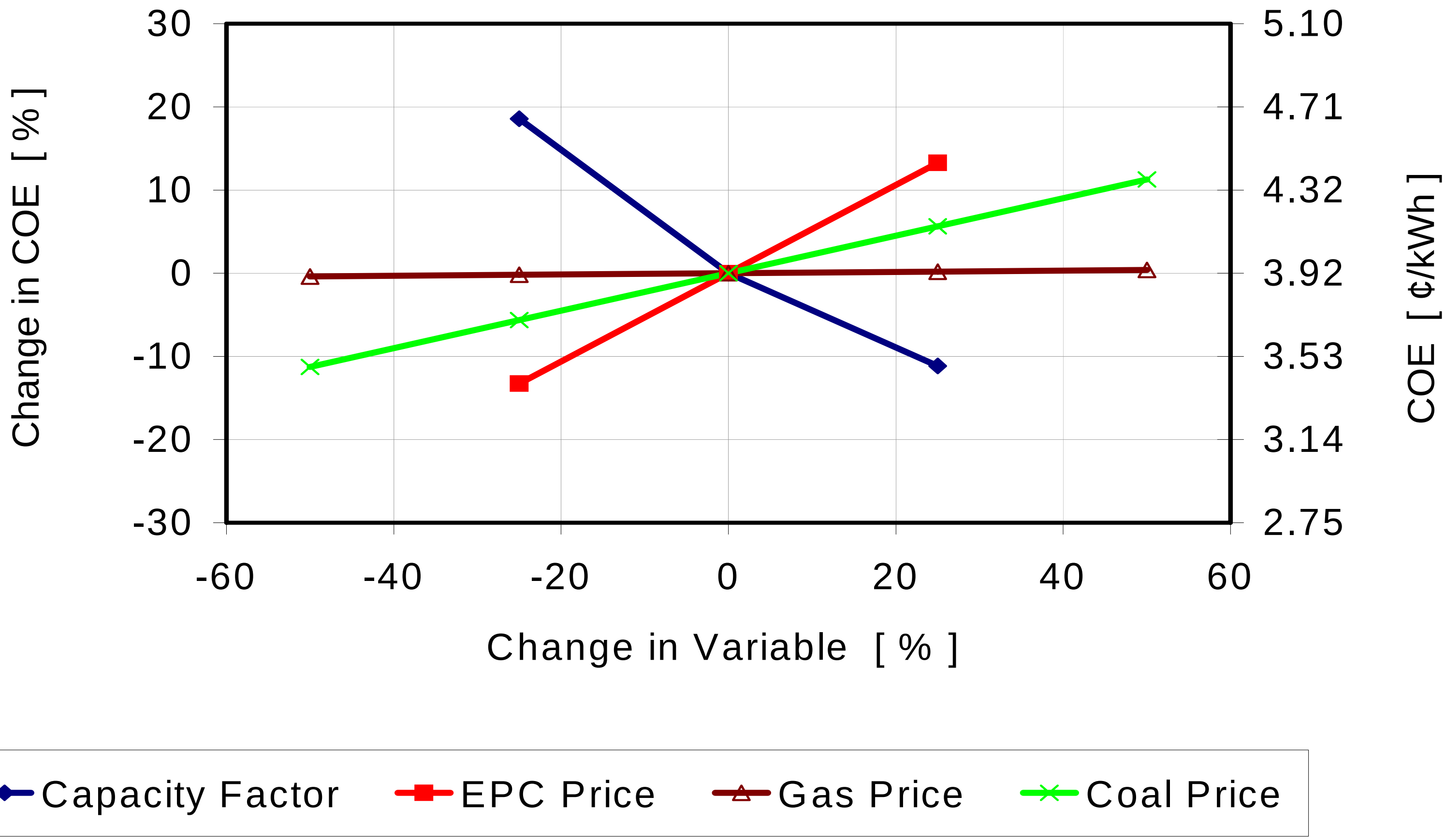


Economic Results
Sensitivity Study Basis

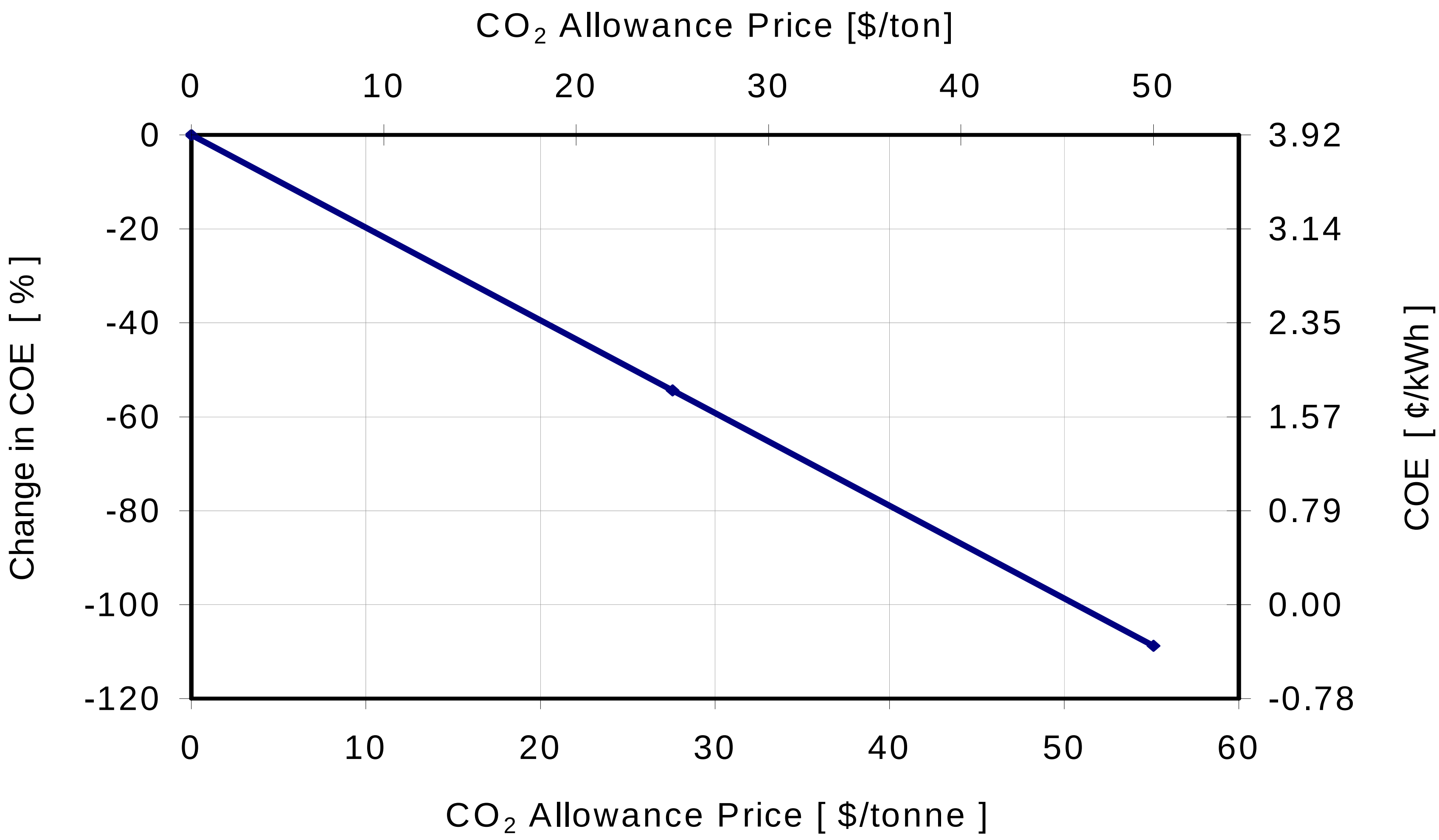
Parameter	Units	Base	Sensitivity Analysis			
Capital Cost	$		Base -50%	Base -25%	Base+25%	Base+250%
Capacity Factor	%	70	--	54	90	--
Coal	$/GJ	2.00	1.00	1.50	2.50	3.00
	$/$10^6$Btu	2.11	1.06	1.58	2.64	3.17
Natural Gas	$/GJ	6.64	3.32	4.98	8.29	9.95
	$/$10^6$Btu	7.00	3.50	5.25	8.75	10.50
CO_2 Sell Price	$/ton	0, 25, 50 $/ton				

- **240 economic evaluation cases assessed**
- **Results allow interpolation to apply results to assess other power plants in the U.S. fleet**

Example Economic Sensitivity
(Case-1 = 90% Capture)



Example Economic Sensitivity
(Case-1 = 90% Capture)



Summary & Conclusions

1. No major technical barriers exist for retrofitting AEP Conesville unit #5 to CO_2 capture with post combustion amine base capture system

2. Compared to the 2001 study, this study with an advanced amine (90% CO_2 Capture case) showed:
   - Improvement in energy penalty of 4.2% points,
   - Reduction in investment cost from $2100 to $1010/kW
   - Reduction in incremental COE from 7.2 to 3.9 ¢/kWh
   - Reduction in mitigation cost from 85 to 51 $/tonne of CO_2 avoided

3. Efficiency penalty was 10.6% for 90% CO_2 capture. Efficiency penalty varied linearly with CO_2 capture fraction.

4. No Sweet Spot—near linear decrease in incremental COE with reduced CO_2 capture level

5. Sufficient results to answer various definitions of "optimal CO_2 capture" from existing plants

Future Work

Apply Results to Existing Coal Fleet

1. Categorize current U.S. PC fleet based on likelihood of CO_2 capture retrofit (“Worst Case Scenario”, “Best Case Scenario”, “Baseline”, etc.)
2. For each level of CO_2 capture (30%, 50%, 70%, 90%), calculate the economic impact on a regional and national level for each category
3. Given the same incremental increase in COE for a new IGCC and PC power plant with 90% CO_2 capture, what is the equivalent % CO_2 capture from the existing power plant fleet for each scenario on a regional and national basis?
4. Make-up power for existing fleet under different scenarios

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